Electricity Innovation Institute

A Framework for Developing Collaborative DER Programs: Working Tools for Stakeholders

DRAFT Report of the E2I Distributed Energy Resources Partnership

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EXECUTIVE SUMMARY

Distributed energy resources (DER) have the potential to bring multiple benefits to energy users, utilities and their customers, DER providers, and the electricity enterprise as a whole. Some of these benefits (discussed generally throughout this report, and in detail in Chapter 2) include:

- enhanced onsite energy efficiency, reliability, power quality and cost control
- more competitive options for customers to acquire energy
- more efficient and less costly distribution system operations
- more reliable distribution and bulk power functions
- lower and more stable wholesale and congestion prices

The inability of today's electricity markets to recognize and account for these benefits where they exist alone or in combination, has led E2I and a group of interested stakeholders to reexamine the processes for integrating DER into those markets. The goals of this collaborative effort are to:

- understand DER costs and benefits from various stakeholder perspectives
- create incentives that accurately reflect and fairly allocate these costs and benefits
- facilitate pilot programs that can show how to reduce DER costs and monetize benefits, and how to better integrate DER into prevailing electricity markets.

This is the second of two reports prepared this year by the Electricity Innovation Institute's (E2I) DER Partnership and its team of consultants. The first was a scoping study[1] performed during the Spring of 2003. Its purpose was to establish a current baseline of DER market conditions in key states; identify the elements of win-win business approaches; and recommend research actions that could lead to more widespread integration of DER into larger electricity markets. The scoping study included interviews with DER stakeholders, a review of recent DER developments in California, New York and New Jersey; and stakeholder-supported research and action recommendations to advance market integration of value-driven DER.

The highest priority recommendations to emerge from that study were:

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[1] *Integrating Distributed Energy Resources Into Emerging Electricity Markets: Scoping Study;* draft report of the E2I DER Partnership; August 2003.

- to develop a catalog of actions that utilities and regulators can take to incentivize DER that adds value to the electricity enterprise;

- to examine the costs and benefits of DER, and how utility rate structures and incentive approaches affect their allocation among key stakeholders; and

- to develop a framework for flexible, collaborative programs to refine and improve existing incentive approaches and implement new ones in several states.

The work reflected in this report is the next step in that process. **Chapter 1** begins by cataloguing some of the approaches and incentives that states and utilities are already taking to facilitate DER (and related demand response) that adds value for electric systems and their customers. The chapter offers insights about what has been tried to date, and starting points for designing the kind of win-win incentives favored by participants in E2I's DER Partnership, to be implemented through collaborative stakeholder programs proposed for 2004-05.

Chapter 1 organizes current approaches according to the primary interests on which each one focuses. For discussion purposes, these include the interests of the distribution utility, the bulk power utility, the DER customer, and society at large (comprised of non-participating utility customers as well as broader environmental and public interests).

The report posits that the *distribution utility's* central focus is to enhance distribution system reliability through cost-effective asset deployment. Regulators and utilities have tried various approaches to DER in pursuit of these objectives, including:

1. requiring jurisdictional utilities to evaluate DER as an alternative to system upgrades, and to develop or procure DER solutions where they represent least-cost or best-fit solutions;

2. targeting incentives to reflect the value that DER can bring to specific local areas or circuits on the utility grid;

3. using customer-sited equipment to improve grid reliability; and

4. rewarding customers for scheduling their loads support grid operations.

The *bulk power utility's* focus for DER is likely to be mitigating wholesale prices and/or relieving transmission congestion. Approaches pursued by regulators and utilities for these purposes have included:

1. facilitating or installing DER that can be dispatched to relieve pressure on locational marginal prices (where available), or to reduce peak transmission costs as an alternative to firm peaking service;

2. purchasing 25-50 MW of more of DER from third-party aggregators who contract directly with customers to assemble supply and demand resources responsive to utility needs; and

3. paying customers (including retail utilities as well as commercial, industrial and residential users) to curtail their loads at critical times, and dispatching aggregated load control as a system resource.

The *DER customer's* focus is usually to increase reliability and reduce energy costs through onsite energy supplies, and/or to expand the energy and financial options available to it. Utilities, DER providers and customers have pursued these objectives through approaches such as:

1. value-added time-of-use pricing services that enable customers to schedule their electricity usage to reduce their bills;

2. installation and operation of onsite cogeneration systems with guaranteed savings for the host facility; and

3. adoption of onsite generation that increases site reliability and reduces net energy costs by taking advantage of hourly pricing options to profit from sales into wholesale markets.

Finally, the *regulatory and societal* focus for DER is to increase the efficiency of energy production, delivery, and use and improve environmental quality. Approaches adopted toward these ends include:

1. customer rebates and equipment buy downs for renewable, 'ultra-clean' or highly efficient DER, and/or combined heat and power (CHP) projects meeting specified criteria; and

2. portfolio standards that require utilities and other load-serving entities to acquire some minimum percentage of diversified renewable resources, including distributed renewables.

Chapter 1 presents specific examples where each of these approaches has been used, describes the programs that have used them and the nature of any incentives employed, and highlights the features that distinguish each example from other similar programs.

Chapter 2 of the report begins to address the next priority recommendation made by E2I's stakeholders: to examine the costs and benefits of DER, and how utility rate structures and incentive approaches affect their allocation among key stakeholders for purposes of achieving win-win outcomes.

In examining DER costs and benefits, the first step is to recognize that a cost to one stakeholder may be a benefit to another, and to distinguish among different stakeholder perspectives. These perspectives include that of the DER customer, other ('non-participating') utility customers, utility shareholders, and society at large.[3] To assess the cost-effectiveness[4] of various activities from different stakeholder perspectives, regulators employ different tests, summarized as follows:

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[3] For analytical purposes, the perspectives of non-participating customers and utility shareholders are grouped together, because the costs and benefits available to these groups come out of the same 'pot', and questions of how they are assigned between the groups are determined by regulators in rate cases.

[4] 'Cost-effectiveness' as used here need not be limited to tangible monetary costs and benefits, but can include intangible ones as well (as the societal cost test does).

- the Participant Cost Test (PCT) reveals whether it is worth it to the *customer* to install DER

- the Ratepayer Impact Measure (RIM) assesses the impact of DER on *utility earnings or rates*

- the Total Resource Cost Test (TRC) measures the *net tangible benefit* available to be reallocated in order to produce a win-win solution

- the Societal Cost Test (SCT) identifies any *additional societal costs and benefits* available from the DER, including externalities (such as reduced pollutant emissions).

The reason to consider all perspectives is to find solutions that can be cost-effective or 'winners' for multiple stakeholders. Looking at all perspectives also aids in program design. For example, one possible allocation method is to establish an incentive (say, a locational credit) that the utility pays to the DER provider – i.e., a cost to the utility and a benefit to the DER provider. A win-win program design in this case would set the incentive payment at a level that would make both the utility's ratepayers and the program participant better off. Stated in terms of the cost-effectiveness tests used by regulators, both the RIM and the PCT benefit/cost ratios are greater than one. Mechanisms that strike such a balance will warrant further consideration.

Specific types of costs and benefits, both direct and indirect, can be identified for each stakeholder group. For example, costs and benefits to the DER customer would include:

	Benefits	**Costs**
Direct	Annual electricity bill savings Annual avoided fuel costs (thermal) Wholesale energy sales Renewable energy credits (sales of)	Annual capital costs; DER maintenance; DER fuel costs (including siting and permitting if customer-owned project) Emissions offset purchases Interconnection study, equipment, and electric system upgrade costs Insurance Other utility infrastructure and operational costs
Indirect	Customer reliability	

Chapter 2 presents similar benefit/cost tables from the perspectives of other stakeholders (the utility, society, etc.), followed by more detailed descriptions of each cost and benefit category relevant to each stakeholder.

Once a qualitative set of costs and benefits is identified from each stakeholder's perspective, the next steps are to quantify them, and to determine whether various combinations of them can yield net benefits that might be re-allocated among the stakeholders to achieve outcomes that benefit all or most of them, without harming others. While it is possible to (and Chapter 2 does) identify generic types of costs and benefits related to DER activities, their *value* to groups of interested stakeholders depends to a great extent on factors specific to each regulatory jurisdiction, each utility and tariff structure, each DER technology and its operational and emissions characteristics, financing strategy, etc. All of these inputs are needed to realistically approximate the *quantitative* values that any DER project or program (consisting of multiple projects) can generate for groups of stakeholders.[5]

E2I has not attempted to design an analytical model that will accommodate all regulatory jurisdictions, all utility tariffs, or all DER technology and project characteristics. However, its team has developed an **Excel spreadsheet model** that illustrates an analytical approach that can be adapted to all of these situations. To keep this version of the model manageable and affordable, it focuses on a single jurisdiction (California) and its three major investor-owned utilities (Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric). The spreadsheet uses actual rate structures and tariffs now in effect or proposed for these utilities, and actual regulatory incentives in place in California in 2003. For other inputs, such as generation and transmission and distribution (T&D) avoided costs, interconnection costs, generation multiplier, and emissions control costs, it allows users to enter ranges of value (e.g., low, medium or high, each corresponding to a specified dollar amount or numeric multiplier).

The model structure enables users to vary numerous inputs relevant to DER projects to see how they affect the costs and benefits flowing to each of the stakeholder groups identified above. Its output reveals which stakeholders profit and which ones pay for different combinations of DER technologies under differing assumptions concerning energy prices, T&D deferral or 'generation multiplier' value, emissions profiles, financing terms, operational characteristics, available incentives, etc. A sample of the model's output summary, also showing the kinds of input settings available to users, appears below.

Costs and Benefits

Units	Levelized $	Analysis Horizon Years (20 Years Max)	10
DER Customer			
Participant Cost Test: Is it worth it to the DER customer to install the DER?			
Annual Electricity Bill Savings	352,547.30	Annual Capital Cost	115,766.11
Annual Avoided Fuel Savings (Thermal)	141,592.01	DER Maintenance Cost	69,374.77
Wholesale Energy Sales	-	DER Fuel Cost	330,216.16
Sales of Renewable Energy Credits	-	Emissions Offset Purchases	9,891.91
CEC Buydown / CPUC Self-gen Program	32,157.25	Interconnection Study Cost	275.96
Incentive / Credit from Other Ratepayers	-	Insurance	-
Incentive from Public Funds / Tax Credit	-	Other Utility Upfront Costs	-
		Other Utility Operational Costs	-
Total Benefits	526,296.55	Total Costs	525,524.93
		Net Benefit	[redacted]
Utility Shareholders and Other Ratepayers			
RIM Test: How much will the impact be on earnings or rates?			
Avoided Wholesale Energy Purchases	411,893.43	Revenue Reductions Due to DER (e)	352,547.30
Avoided Generation Capacity	-	System Upgrades	-
Avoided T&D Capacity	25,489.36	Interconnection Study Cost	275.96
Customer Payment for Interconnection Study	275.96	Credit to DER Customer (b)	-
Credit from Public Funds / Tax Incentive (c)	-		
Total Benefits	437,658.77	Total Cost	352,823.28
		Net Benefit	[redacted]
Combined DER Customer, Shareholders, Other Ratepayers			
Total Resource Cost Test: What is the net tangible benefit that can be reallocated to produce a 'win-win'?			
Sum of DER Customer, Shareholder, and Other Ratepayer Perspectives			
		Net Benefit	[redacted]
Incremental Societal Value			
Societal Cost Test: What are the additional net intangible benefits?			
Reduced Central Generation Emissions	13,612.35	DER Emissions	60,400.77
		CEC Buydown / CPUC Self-gen Program (d)	32,157.25
		Public Funds / Tax Credit to Utility (c)	-
		Public Funds / Tax Credit to Customer (a)	-
Additional Benefits	13,612.35	Additional Costs	92,558.02
		Incremental Societal Net Benefit	[redacted]
		Net Societal Benefit (TRC+Societal)	[redacted]

Notes:
(a) transfer assumes there is no incremental change in rates, otherwise this would appear in RIM test
(b) transfer assumes the credit leads to a change in rates to non-participants, otherwise this would appear in the societal cost test
(c) transfer assumes the credit would not increase costs to shareholder or non-participants
(d) we assume that the CEC / CPUC programs will not increase the level of the current Public Goods Charge
(e) Net of Standby Charges (if not a DER technology) and Exit Fees

Input Settings

Avoided Costs	
Wholesale Energy Forecast	SP15 9/8/2003
Generation Multiplier	Medium - 3X
Residual Net Short Position	Medium - 5%
Generation Capacity Avoided	Zero Cost
T&D Avoided Cost	Average (50%)
Customer Characteristics	
Utility	SCE
Customer Rate	SCE: GS-2 Proposed
DER Type (Qualify for DER Rate?)	Non-DER (Does not qualify)
Customer Size (kW)	Enter --> 1500 kW
Customer Load Factor	90% Load Factor
DER Technology Type and Financing	
DER Type	Caterpillar G3516 LE - 800kW w/C
DER Operation	High Cap - 2 Outages
DER Financing	10-Years
Natural Gas Rate (If Nat. Gas)	Cogen Discount Customer
Diesel Cost (If Diesel)	Industrial
Interconnection Cost	Medium - $2000
Customer Payment for Interconnection	High - 100%
Other Inputs	
Rebates	California CPUC
Emissions Costs	Low
Attainment Area	Non-Attainment
REC Credits	None - $0/MWh

Where a model run reveals substantial net benefits for one stakeholder group and net costs for another under relevant cost-effectiveness tests, it suggests the possibility that re-allocating some of the costs and

5 Determining these values and their potential for tradeoffs among stakeholders is a very different exercise than estimating the value of a specific DER project to an individual DER customer, site host or owner/operator. EPRI and others have developed models for that purpose, and their objectives and functions are different from those described here.

benefits generated in that scenario could result in net benefits to all parties and net costs to none (or lower costs to some). In doing so, it identifies scenarios that may be subject to constructive collaboration among stakeholders to achieve benefits for all of them – considering that scenarios that benefit one stakeholder group at the expense of others often face serious opposition resulting in project failures that benefit no one.

To extend the analysis that the model makes possible, **Chapter 3** focuses on methods available to allocate DER costs and benefits among stakeholders. For regulators and policymakers, utility revenue setting and rate design are the critical points where DER intersects with the utilities they regulate. The rates that end-users pay for grid-supplied electricity largely drive DER economics, and the ways that utilities are compensated for supplying that electricity can determine their receptivity to DER development. This means that utility revenue setting and rate design offer important tools to shape DER incentives, and thus help or hinder DER integration into emerging electricity markets.

While the prospect of reducing their bill from the utility can induce customers to pursue DER, the flip side for the utility is that any bill reductions the customer achieves can reduce utility earnings, if revenue reductions are not offset by equivalent cost savings to the utility. One objective of rate design is to ensure that rates present price signals to customers that mimic the costs utilities actually incur or avoid. Designing efficient rates and appropriate utility pricing structures therefore requires an understanding of how utilities incur costs, which of these costs DER can actually affect, and under what circumstances it can affect them.

Table 1 in Chapter 3 provides this kind of information. It shows that DER can reduce costs for a *subset* of the total costs that a utility must recover from its customers. However, utility rates are designed to recover the *total* costs plus a reasonable return on utility investment. This means that customer bill reductions from DER that are not tied to the subset of costs actually reduced can exceed the true savings available to the utility (especially for "wires-only" utilities that capture no savings from reduced generation capacity and energy). Because mismatches can occur between customer bill reductions and utility cost savings, utilities are sometimes averse or at least disinclined to promote DER. To minimize this source of disincentives, it is important that regulators set policies and design rates that align customer bill savings with utility cost savings, so that utility and customer interests move in the same direction.

Basic rate forms that can make it easier or harder to align these interests include volumetric (energy) charges, fixed charges, and demand charges. Rate designs with high fixed and/or demand charges help ensure utility cost recovery independent of customer energy usage, so they minimize utility financial incentives to oppose DER. On the other hand, these rate forms provide weak price signals or none at all that would induce customers to adopt DER that could benefit the system, the environment or other ratepayers, and they make it difficult or impossible for customers to capture economic benefits from DER, limiting DER deployment to 'super' cost-effective resources.

The argument for large fixed-cost rate components rests on the idea that many utility costs (especially for wires-only utilities) do not vary much in the short run, and that short-run marginal delivery costs are often very low, sometimes approaching zero. However, many of those same costs can vary in the long run, and it is important to recognize this in setting fixed charges. One option is to base fixed charges on long-run marginal costs, and to use alternative methods of setting revenues and allocating risks to address concerns about utility revenue collection and stability. These methods can provide strong profit incentives for utilities to maximize their own efficiency as well as that of their customers.

Two such methods discussed in the report include 'demand subscription' and non-firm standby options. Both offer alternatives to conventional standby charges that often discourage DER development. Standby rates typically assume that the utility retains its obligation to supply the customer's load when the customer's onsite generation is down for maintenance or unscheduled outages. Demand subscription and non-firm rates instead assume that customers should be able to choose the level of standby they need for their operations. For DER customers that do not require firm service or value it highly, demand subscription offers a way to pay only for the capacity they do need and value, accepting some level of risk in return for reduced costs. For small DER customers whose back-up requirements would not drive T&D peaks in any case, non-firm service offers a way to secure back-up service for most times of the year, except possibly during periods of utility peak demand. Both alternatives to conventional standby rates also expand DER customer choices, without imposing the costs of these choices on other stakeholders.

A third method that can help align utility and DER customer interests is a 'two-part' rate form that protects utility revenues while providing price signals to customers to help control utility costs. This rate form collects the customer's historical billing, but it also charges for increased usage (or credits reduced usage) at the utility's marginal cost – i.e., the cost of expanded facilities avoided or deferred through customer DER initiatives.

If DER benefits are large enough, these rate innovations can help customer-side DER into the market-place without prejudicing utility shareholders or non-participating customers. However, the modeling tool described above suggests that, at least using current California rate assumptions and today's technology costs and benefits, DER may require more leverage to significantly penetrate electricity markets. One way to obtain that leverage is to explicitly recognize additional DER values where they exist.

This can be done in various ways. California now requires utilities to consider DER as an alternative to distribution upgrades, and to take steps to procure it where it appears to offer a least-cost solution. New York requires its utilities to evaluate DER for T&D projects whose costs exceed certain benchmarks, and oversees a pilot program that requires utility RFPs to procure DER where it can defer T&D capacity needs. Costs that utilities incur for prudent DER procurement, including the costs of any incentives needed to direct DER to high-value areas, can be funded from utility transmission or distribution budgets, and capitalized like traditional plant investments to protect utility shareholders.

Another way to capture additional values offered by some DER is to monetize the societal costs of emissions. In that case, benefits accruing from clean DER technologies could be paid for out of 'public goods' or 'system benefit' surcharges levied on all utility sales in some jurisdictions. Utility shareholders are not harmed because such funds are already earmarked for public interest programs and funded through a dedicated rate component, and utility earnings are unaffected. Other options to capture potential DER benefits include recognition of a 'generation multiplier' effect where DER operations can lower market clearing prices for all customers, and provide more efficient market rules for energy, capacity and ancillary service markets. These could encourage transparent markets where DER customers are easily compensated for the societal or system value their resources provide, or assure that a day-ahead bidding system accommodates customer resources.

Chapter 3 closes with a brief discussion of higher-level regulatory changes such as revenue-based PBR that could replace utility incentives to resist DER, with incentives to encourage it where it adds value. It also suggests that there is some room for regulatory experimentation at this stage of DER development, and describes some alternative arrangements to implement DER opportunities that benefit multiple stakeholders.

Chapter 4 addresses the final high priority recommendation of E2I's stakeholder group, to initiate flexible, collaborative pilot programs in several states to refine and improve existing incentive approaches and implement new ones. Chapter 4 begins that process by offering a framework for developing such programs. The framework builds on the catalog of approaches presented in Chapter 1, the DER cost/benefit descriptions and modeling tool, and the discussion of utility costs and rate designs to outline ways that willing stakeholders can collaborate to develop innovative pilot programs based on these tools.

Depending on the utility system and its customers, these pilot programs might provide anywhere from a few megawatts to a few thousand. They might involve some minimum number of customers, or some threshold level of demand reduction or curtailment. They will likely include multiple individual DER installations employing diverse technologies, which may remain in place and continue to provide benefits long after the formal pilot program ends. By developing solid experience with various forms of DER incentive approaches under real-world conditions, these programs should also serve as thoughtful models that other jurisdictions can cost-effectively replicate, adapt to local conditions, and improve over time. In the end, the approach described in the framework can not only facilitate collaboration on limited pilot programs, but can provide a solid foundation for more wide-ranging DER market integration efforts.

The pilot programs E2I envisions can be much more than DER technology demonstrations. They can also demonstrate:

- the added value that DER can bring to the electricity enterprise
- more constructive ways for DER participants to communicate and cooperate
- new ways to optimize benefits for multiple stakeholders
- creative rate design and other regulatory incentives targeted specifically to encourage DER that adds value beyond conventional electricity supply
- innovative departures from 'business as usual' in the DER marketplace

The framework is organized in four parts. The first deals with structuring the collaborative process and defining the program's scope and objectives. The second introduces basic strategies for participants to consider in developing programs, and outlines the stakeholder needs that each strategy can address. The third part discusses options available to tailor each basic strategy to local conditions. And the final part presents a detailed example showing how the framework approach, the catalog and rate discussion discussed above, and the cost/benefit modeling tool can be combined to evaluate a potential CHP pilot project or program.

Important questions to ask in structuring such a collaborative include the following, all of which are discussed in the report:

- Which stakeholders should participate, and how?

- What are the collaborative's structure and ground rules, and how can it establish trust among the participants?

- What are the collaborative's objectives and priorities, and what can it accomplish that the state's or the utilities' ongoing DER activities cannot or have not?

- How will the collaborative measure results and evaluate success?

- How can it foster innovation and experimentation?

Once these considerations have been addressed, participating stakeholders can use the framework to outline projects that can meet their defined objectives and advance their priorities, and can form project teams to move forward with actual programs.

The framework outlines three basic strategies for consideration by collaborative participants. These include. –

1. ***Leveraging DER value*** by recognizing multiple value streams that today's markets may not;

2. ***Introducing efficient incentives*** to facilitate and deploy DER in those situations; and

3. ***Eliminating barriers*** to DER that inhibit innovation, but serve little public purpose.

Leveraging DER value refers to approaches that capture and allocate among stakeholders multiple value streams that can flow from DER selected, sited, sized, and operated to create value for more than one group of stakeholders. The description of DER costs, benefits and allocation, and the modeling tool described earlier can help participants develop a common understanding of what those value streams are, what they are worth, and what it means to allocate them in different ways. This modeling tool enables participants to tailor their assumptions and analysis until they are comfortable with its objectivity and accuracy, and to assess a variety of impacts easily and with some confidence in the results.

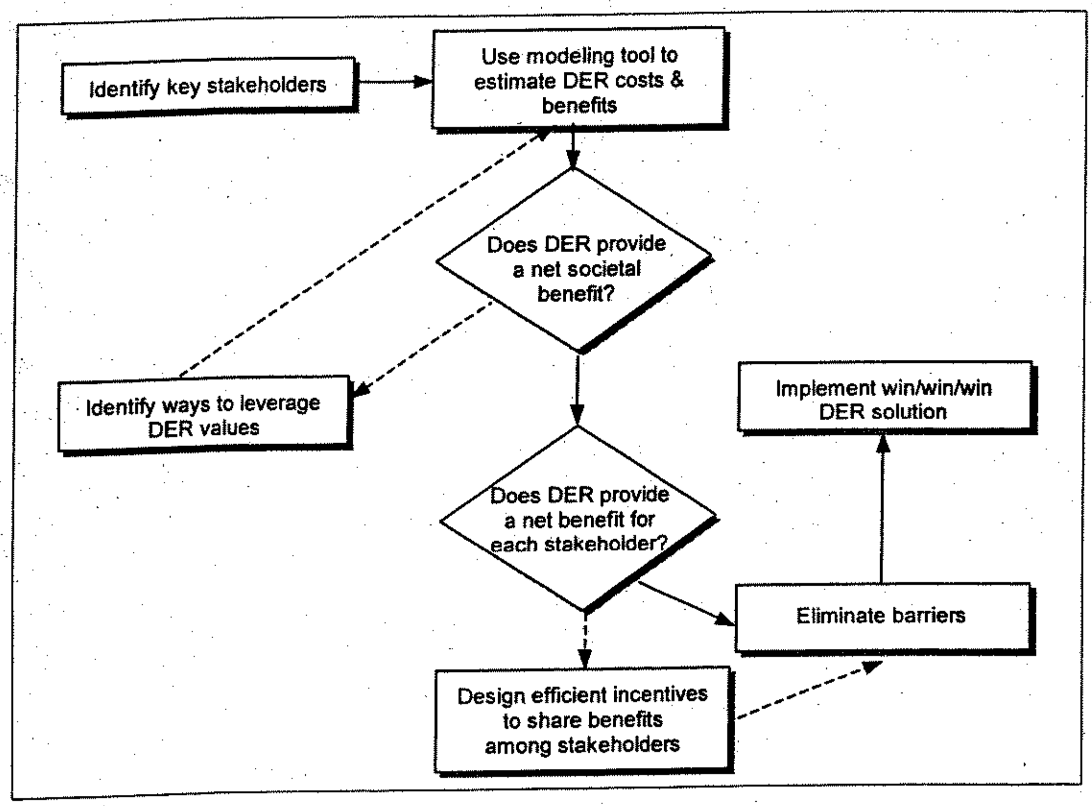
Introducing efficient incentives refers to initiatives that send price signals to utilities, end-users, and DER providers that better reflect the true costs and benefits of DER solutions in specific situations. The review of these issues in Chapter 3 and some of the program examples presented in Chapter 1 should help frame this discussion.

Eliminating barriers here refers to eliminating or reducing obstacles to DER siting, installation, operation, and value recognition in the market. It includes minimizing transactions costs for all participants, from project inception to completion. Examples are presented later in the framework discussion.

These three strategies overlap at times, and are not mutually exclusive. Collaborative programs that incorporate some or all of them should make it easier for utilities to signal where DER adds value to their systems. They should also help end-users adopt DER solutions that supplement and reinforce utility service, while serving their own interests and benefiting other stakeholders.

Chapter 4 provides tables illustrating how the three basic strategies relate to the needs of each key stakeholder group, and where each strategy might be used to shape collaborative programs that meet those needs. Since these strategies are general in nature the discussion also presents more specific options to tailor each of them to local needs, with the hope that participants will be able to address not only the interests of individual stakeholder groups, but the common or complementary interests of all groups.

Chapter 4 concludes with a detailed example illustrating how the framework approach can work when applied to a sample CHP project in California. The process to identify, leverage and reallocate costs and benefits is shown below:



Using baseline input assumptions, the California CHP example initially shows that the DER customer loses about $600 annually, while utility shareholders and/or other ratepayers gain about $60,000 and society 'pays' nearly $80,000 (in the form of increased emissions and mandated self-generation incentives). Using these assumptions, the project's net cost to society is about $19,000.

Following the process diagram above, the next step is to *"Identify ways to leverage DER values."* Once this is done – by locating the CHP project in a distribution area where the utility plans to upgrade its grid, in this example – substantial values for avoided distribution capacity are factored into the model, changing the net societal benefit from a negative $19,000 to a positive $98,500.

However, all of the additional benefits accrue to the utility and/or other ratepayers, not to the DER customer or as an incremental benefit to society. Stakeholders would next look for opportunities to re-allocate some of the benefits so that all key stakeholders are better off, or at least not worse off than they would be without the project. In the example, this is accomplished through a form of incentive known as a 'distribution credit' that the utility is willing to pay the DER customer for locating in an area targeted for early upgrades. Here the utility is willing to offer an $85,000 yearly incentive for CHP sited in the target area. It is willing to share part of the benefit that might otherwise accrue to it because the project will save the utility a levelized annual T&D capacity investment of about $117,000.

Because the project now provides a net benefit for each stakeholder, attention now turns to the third strategy – eliminating barriers – to increase the overall cost effectiveness of the project, possibly by shortening the time it takes to complete the project, reducing processing costs that result from unnecessary barriers, and looking for ways to work through transactional barriers. In this example, the barrier happens to be the disparity in financing periods between customer lease or purchase financing (typically short-term, up to 10 years), and utility financing (typically long-term, often recovered over a 30-year asset life). Increasing the DER financing term for the CHP equipment from 10 to 20 years reduces the customer's annual equipment cost by nearly $37,000, increasing the net societal benefit by the same amount. If necessary to achieve a win-win outcome, this benefit in the first years of the project could also be
re-allocated among other stakeholders whose participation is needed to make the project go forward..

The example discussed is only one of many that could be used to illustrate how the framework can be applied, and how the other elements described in this report – the catalog of approaches, the cost/benefit and allocation discussions, and the modeling tool – can be combined to shape collaborative DER programs.